Amendments to the Specification:

The following has been inserted on page 8, line 21, through page 10, line 14.

Velocity of the pore fluids in the reservoir rocks can be measured by using the well-known Time-Average equation developed by Wyllie et al (1958). This equation is often used to relate the velocity of the reservoir formation and the porosity.

1/ Formation velocity = Porosity/ Pore Fluid Velocity + (1 – Porosity)/ Velocity of Rock Matrix.

Different wireline well logs are run as a normal routine, to identify the rocks, evaluate the reservoir formations, and to measure their petrophysical and elastic properties. The reservoir formation velocity is routinely measured using wireline Sonic Logs. In addition to the well logs coring of the reservoir formations is carried out for detailed analysis. The core of the reservoir rock is the only direct source of data for a particular reservoir. Oil and Gas exploration industry uses well logs and core evaluation as a general practice for reservoir characterization. Reservoir characterization instruments and coring tools are readily available in the industry to measure the elastic and petrophysical properties of the reservoir rocks and to obtain samples of the reservoir fluids.

PAGE 5/17 * RCVD AT 1/7/2004 12:11:49 PM [Eastern Standard Time] * SVR:USPTO-EFXRF-1/0 * DNIS:8729306 * CSID:7135212873 * DURATI N (mm-ss):05-14

Core measurements provide an accurate value of the velocity of the rock matrix and the porosity of the reservoir rock. The industry has the equipment and knowledge for the measurements of the acoustic velocity of a core sample under a wide range of pore and confining pressures. Measurements can be made either with dry or saturated core samples. The texture of the core is analyzed to determine the grain size, shape, and distribution. Porosity and crack density is measured. Once the reservoir formation velocity is known from the Sonic Log, and Velocity of the Rock Matrix and Porosity is measured using the core sample, the velocity of the Pore Fluid can be calculated, using the Time-Average equation described above. In the case, where the samples of the reservoir fluids are available, direct measurements of the reservoir fluid properties can be made. The Modulation Formation Tester (Schlumberger) tool provides formation and hydrostatic pressure, temperature and fluid resistivity while fluid sample is being acquired. There are similar tools available from other service companies. The recovery of in situ pore fluid provides samples, which can be used to analyze the pore fluid properties. The velocity of the pore fluid can be measured as a part of the analysis. The velocity derived from in situ pore fluid measurements can be used to calibrate the velocity derived using Time-Average equation.

PAGE 6/17 * RCVD AT 1/7/2004 12:11:49 PM [Eastern Standard Time] * SVR:USPTO-EFXRF-1/0 * DNIS:8729306 * CSID:7135212873 * DURATION (mm-ss):05-14